Comprehensive Market Design Stakeholder Comment Matrix Technical Working Group – *FINAL*

Please complete this matrix by February 27, 2018, and upload it to the “Feedback” folder on the CMD SharePoint site. The AESO will post all comment matrices received from working group members on www.aeso.ca. **Please note that the names of the parties submitting each completed comment matrix will be included in this posting.** The AESO does not intend to respond to individual submissions. If you have any questions about this comment matrix, please email capacitymarket@aeso.ca

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Date: February 27, 2018

CMD Key Design Questions	Comments and / or Recommendations

1. UCAP: Can you support the availability factor/capacity factor over the 100 hours of smallest supply cushion being used to calculate the UCAP?	***No – determination of availability factor using the 100 hours of smallest supply cushion over the past 5 years to calculate UCAP creates unfair treatment for existing generators and unnecessarily increases costs to consumers.*** Specifically:
	• It is discriminatory to existing generators. It is not consistent with the principle of fair treatment for new and existing resources because it disadvantages existing assets. Use of 5-year historical availability arbitrary assesses existing asset performance under a different electricity market structure that did not provide the same availability incentives as the current market structure, whereas new assets will be assessed on a forward-looking basis, meaning that existing assets would be retroactively penalized through a lower UCAP value that is unreflective of an asset's actual reliability contribution.
	• It does not assign risk to the participant that is best suited to manage that risk. The approach of having individual generators (rather than the AESO) manage planned outage risk, combined with the AESO's performance penalty framework, forces accountability for managing planned outages onto individual generators when they have no ability to reduce the need for planned outages (all equipment requires routine maintenance) nor to ensure that outages do not overlap. This would:
	    ○ Increase costs to consumers in two ways – first by increasing the risk that individual generators price into their capacity bids, and second by increasing energy price volatility due to the potential for overlapping outages that are not centrally coordinated.
	    ○ Threaten system reliability by limiting opportunities for generators to take planned outages for necessary routine maintenance needed to ensure reliable operations and will also likely result in higher and more volatile costs for consumers.
	• It degrades the price fidelity of the capacity market signal by procuring less capacity than generators are able to provide to the system (as demonstrated by appropriate reliability modelling). This will lead to higher costs to consumers since the AESO will be procuring a smaller amount of capacity without any change to generators' fixed costs, so generators will need to bid higher to recoup the same fixed costs over fewer MWs. Moreover, by buying fewer MWs, the AESO has created a smaller capacity market and that will exacerbate the volatility of the capacity price in response to new entry and retirements.
	• It is not consistent with reliability modelling. Because the AESO has not performed reliability modelling, it cannot measure whether the 100-hour methodology effectively captures generators' true reliability contribution. No other capacity market uses a 100-hour approach to calculate UCAP and the AESO has not provided detailed justification to demonstrate how such an approach would result in improved reliability and lower costs to consumers.

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	To better align UCAP calculations with expected reliability contribution and help consumers procure the lowest cost capacity, we recommend that the AESO: • Use a 5-year historical 1-EFORd calculation to determine UCAP, consistent with other capacity markets and with the AESO's proposed all-hours reliability modelling approach. This ensures that both new and existing assets receive fair treatment in the calculation of their UCAP, is transparent for all market participants to calculate, and provides a clear path for generators to manage their performance and improve operations to increase their reliability contribution. • Create a bounded mechanism for existing generators to challenge UCAP calculations based on historical data that are unrepresentative of likely future performance. This will help ensure that resources are compensated fairly for their reliability contribution and that consumers do not overpay for capacity. • Centrally coordinate and approve planned outages, and exempt approved planned outages from penalties. This will keep unnecessary risk out of generators' capacity bids and reduce price volatility in the energy market by limiting overlapping outages, which will reduce costs to the consumer. **<u>Detailed Response:</u>** The UCAP approach currently proposed by the AESO is not aligned with reliability modeling and will create unintended negative consequences for the system. The UCAP for intermittent resources should be validated from resource adequacy modeling. Not properly aligning UCAP with contribution to resource adequacy will create unfair treatment for existing resources, distort market outcomes, increase costs to consumers, and ultimately undermine reliability. Each resource's contribution to reliability must be measured in an equitable fashion, meaning that the choice of UCAP methodology should be based on robust and detailed resource adequacy modeling. With this as the basis for UCAP methodology selection, TransAlta supports and asks the AESO to select UCAP methodologies that most accurately reflects the different capacity resources' contributions to supply adequacy. We believe that a 1-EFORd approach will be better aligned with reliability modeling and will better capture resources' contributions to supply adequacy rather than simply aligning with certain market participant preferences. Beyond better capture of reliability contribution, 1-EFORd provides clearer path for generators to improve their performance and reliability contribution. Generators have more ability through appropriate maintenance and investment to reduce their EFORd than to increase their availability during the tightest 100 hours. EFORd increases with the age of an asset and it is fair to penalize lower performing units for a lower EFORd. While TransAlta supports using 5 years of historical data with a 1-EFORd approach, we have concerns about the use of 5 years of historical data to estimate future planned outages as well as the potential for unrepresentative data to complicate a resources' UCAP calculation. For example, historical data on planned outages during the energy only market structure may not be reflective of how

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	assets will operate to manage future performance. Given that the capacity market design was unknown to resource owners in the past, owners would not have had comparable market signals and incentives to optimize planned outages. This means that assets would be retroactively penalized through a lower UCAP value that is unreflective of an asset's actual ability to contribute to system reliability. The use of 5 years of data also captures planned outages that are on multi-annual outage cycles, which can result in under and over-estimating planned outages in the capacity delivery period. For example, if major planned outages are on a three-year cycle, the use of 5 years either includes two major planned outages that unduly underestimates UCAP if major planned maintenance is not expected to occur in the delivery year or overestimates UCAP if the 5 years includes only one cycle but major planned maintenance is expected in the delivery year. Additionally, the use of five years of data captures non-recurring, unexpected forced outages. For example, Keephills 1 experienced a force majeure related to a winding failure in 2013 which resulted in the unit being on extended outage. Keephills 1 will be assigned a lower UCAP based on 5 years of historical data than it is expected to deliver in 2021 because it is highly unlikely that the unit will experience a similar extended forced outage in the future. Therefore, the AESO should establish a process to share UCAP calculation data with resource owners and create a bounded mechanism for resource owners to challenge assigned UCAP values prior to each auction, as operators have the best understanding and data related to their units. A dispute resolution process is important to ensure that the AESO is providing a UCAP that is truly reflective of resource's capacity value. Such a process will be critical in the first few years of market opening given that historical data is based on operation in an energy-only market and not necessarily indicative of future performance under a capacity market.
2. UCAP: Can you support the UCAP calculation being based on 5 years of historical data?	***Yes – please see response to Question 1.***
3. UCAP: Are there risks with including planned outages in the availability factor data used to calculate UCAP? If so please describe.	***Yes – please see response to Question 1.***
4. Demand Curve: Do you have any feedback on the material presented in the CMD 1? Note: AESO and the WG will revisit the shape of the demand curve once draft outputs from the Resource Adequacy model are available.	***Yes – the demand curve presented in CMD1 is too short, too narrow, and too steep, all of which will fail to send the appropriate capacity pricing signals to existing and new generators when they are needed for reliability.*** The primary objective function of the capacity market is to support the reliability of the electricity system (i.e., to keep the lights on) in a manner that keeps costs reasonable for consumers. As such, the demand curve (which is primarily comprised of the cap, the resource adequacy target, and the foot) must send the appropriate capacity pricing signals to keep cost-effective existing generators from retiring prematurely while encouraging new generator entry when needed for reliability.

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	The proposed demand curve fails in this mission for the following reasons: • The price cap set at maximum of 0.5x Gross CONE or 1.75x Net CONE is too low for a small market that must ensure new capacity is sufficiently incentivized to enter in a timely fashion, particularly when energy market prices are so uncertain with carbon taxes which may change over time and generators' bidding behavior in the energy market. For example, if AESO were to expect bidding above SRMC, increased energy revenues would reduce Net CONE and therefore lower the price cap, putting downward pressure on capacity prices. But new entrants may not be able to finance their investment with lower capacity prices. This creates a reliability risk for the Alberta system if substantial existing generation were to exit the market without accompanying new capacity entry. • The resource adequacy target of 400 MWh EUE (which is based on the single worst reliability occurrence in the last 15 years) is equivalent to a low level of reliability. Indeed, such a low reliability target would involve supply interruptions of more than 4x the amount of supply interruptions experienced on average over the last 15 years. • The AESO has added an inflection point, which comes in about 4% higher than the resource adequacy target and at 0.875x Net CONE. The AESO has not provided any concrete basis for this inflection point, but it does make the demand curve steeper and the capacity market more prone to big swings in capacity prices. • The foot is too short coming in at the 25% reserve margin because it essentially means very low capacity prices even at reserve margin levels of 20%. Such a short foot is likely to yield unnecessary premature retirements of cost-effective existing resources. This would require expensive new entry to replace retired capacity, increasing long-term costs to consumers. To create a more effective demand curve, the AESO should: • Set the price cap at the maximum of 1.75x Net CONE or 1x Gross CONE to ensure new capacity is sufficiently incentivized to enter when needed for reliability. • Base the resource adequacy target on the historical <u>average</u> actual unserved energy and loss of load hours rather than the single highest occurrence, which will help build the system towards an acceptable level of reliability at reasonable cost. • Set the intersection with the resource adequacy target at 1x Net CONE. • Set the foot at 35% the resource adequacy requirement to prevent retirement of cost-effective existing capacity and save consumers money. **<u>Detailed Response:</u>** TransAlta is deeply concerned with the change in resource adequacy target from 100 MWh of Expected Unserved Energy (EUE) to 400 MWh of EUE. The rationale provided by the AESO for the change was that stakeholders voiced concerns about over-

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	procurement under a stronger resource adequacy standard. We fundamentally disagree that selecting the right reliability standard can be simplistically characterized as a choice between "over-procurement" or "under-procurement". First, over-procurement is a misused and poorly defined term, as procuring capacity beyond the resource adequacy target is not without benefit to consumers – rather, it provides extra capacity insurance that creates an even more reliable system. Second, procuring capacity above a reasonable resource adequacy target and procuring capacity below a reasonable target under-procurement do not have proportionate consequences for Alberta consumers and investors. Procuring too little capacity degrades the reliability of the electricity system and has severe negative consequences for the economy and threatens the safety of Alberta consumers. It also erodes private investors' confidence in the market design, which can lead to a lack of new private investment, ultimately increasing consumer costs and further threatening system reliability. Therefore, TransAlta strongly encourages the AESO to set the resource adequacy target based upon the historical average of actual unserved energy and loss of load hours rather than the single worst case of unserved energy. Setting the standard on the highest level of actual unserved energy from the last ten years of historical performance creates a standard that is too low, raises resource adequacy and reliability risk for Albertans and does not adequately address the capacity and energy market trade-offs to achieve the lowest cost for consumers. For example, if the Alberta system had experienced repeated events with 400 MWh of unserved energy over the last ten years (rather than just one), the system would have been markedly less reliable than it actually was, to the detriment of consumers and the economy. Given our concerns with the proposed resource adequacy target, we would like the AESO to provide historical data on actual unserved energy and loss of load hours for each year since 2000. We also request that the AESO provide the equivalent EUE, loss of load hours, and reserve margins for a 100 MWh EUE standard and a 400 MWh EUE standard. This information is necessary to fully understand the reliability impacts associated with the change in the resource adequacy standard. TransAlta also has deep concerns about the shape of the demand curve and the unintended consequences it creates given the size of the Alberta market relative to the size of a typical generation unit. The choice of a low-price cap, inflection point, and short foot creates a noticeably shorter, narrower, and steeper curve than demand curves used in other capacity markets – see below:

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	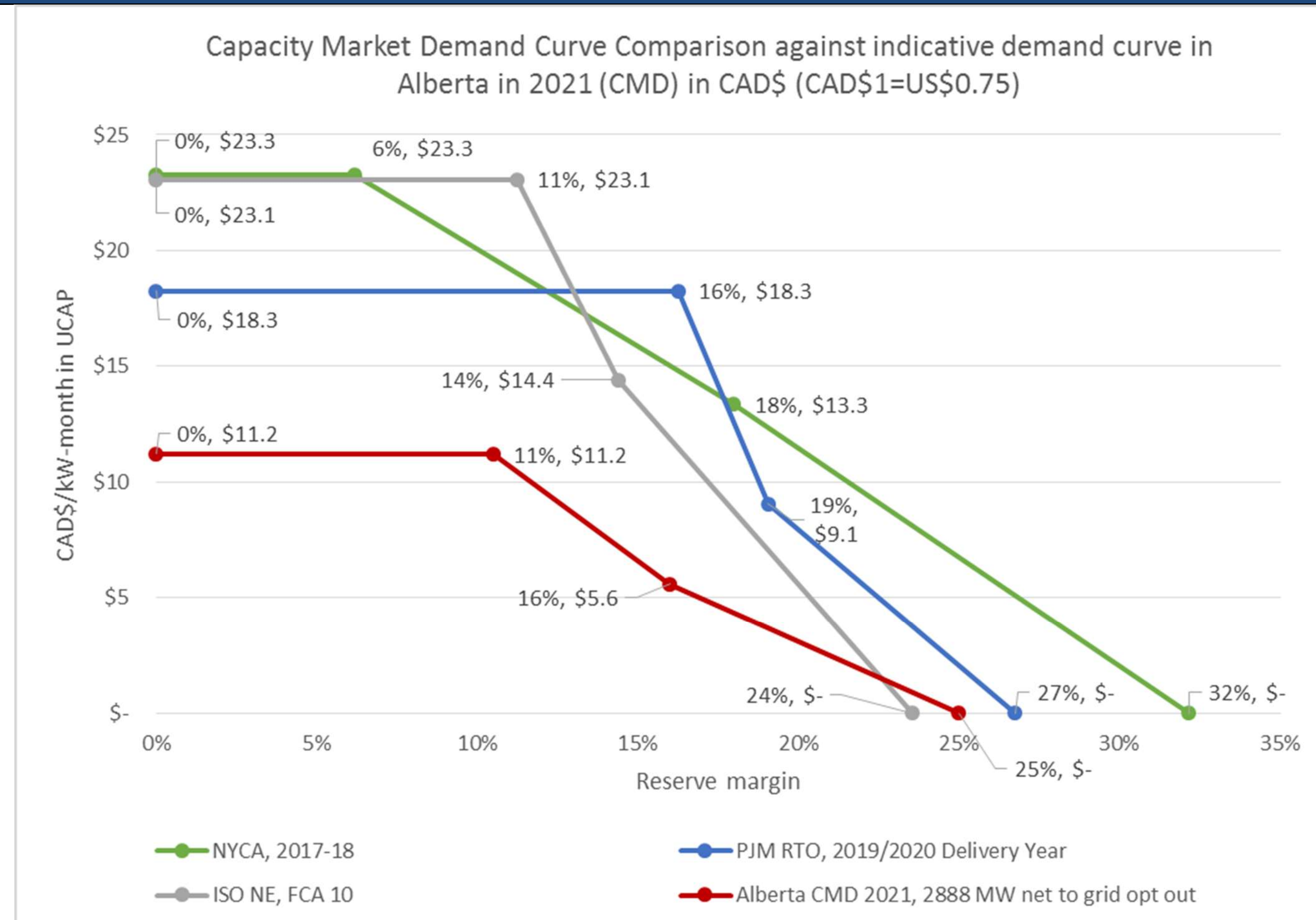 With a low-price cap, the proposed demand curve provides very little margin for error in correctly calculating Net CONE. In contrast, in other US markets with demand curves, a 400 MW unit would have an impact that is half the size of the impact projected for Alberta. Moreover, the proposed steep demand curve amplifies the capacity market power problem. Finally, given Net CONE can be highly uncertain three years out, particularly given uncertainty over the future level of the carbon tax, a Gross CONE consideration

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	for the price cap formula will better safeguard the capacity market and ensure adequate investment signals, and cost-effective reliable service for consumers. Additionally, the short foot would fail to incentivize investment in new generation when it is needed for reliability as well as failing to keep cost-effective existing generators from retiring. Specifically, it will exacerbate the current level of investment uncertainty by distorting price signals and will ultimately encourage undesirable year-to-year price volatility, particularly in such a small market. For example, for every 400 MW of capacity added to system, prices fall by \$3/kW-month and for every 400 MW of capacity not clearing, prices increase by \$5/kW-month. This means that the addition or subtraction of just one typically-sized generating unit could translate into annual cost swings to consumers of \$20 million. This type of curve provides an unwelcomed level of instability at a time when the market has undergone tremendous change, and we are not convinced that the shape of the demand curve adequately captures the unique small size of the Alberta market nor the need to accommodate the near-term coal retirements and supply mix changes that Alberta faces. Rather, we believe that the demand curve should contain the following features: • A higher price cap – given uncertainty over energy and ancillary service revenue calculations three years out, the AESO should adopt a curve capped at the maximum of 1xGross CONE or 1.75x Net CONE to account for the possibility that AESO may err on the Net CONE estimation or that Net CONE values will drop based on future energy market expectations. • A longer foot – a foot that extends to a 35% reserve margin is necessary to safeguard resource adequacy as Alberta moves through the market design transition to prevent premature retirement, mitigate high capacity price volatility, and provide a stable investment price signal.
5. Load Forecast: Can you support the proposed approach to forecast load? Are there any outstanding comments or concerns with the proposed approach?	***Generally, yes, but market participants need greater transparency from the AESO on modeling methodologies and sources for forecast inputs, particularly information on how behind the fence cogeneration load is modeled.*** Given that behind-the-fence load represents a significant 22% of load in Alberta, generators and consumers must be confident that there are adequate reliability safeguards in place to prevent free-riding and cost-shifting in order to ensure the reliability of the system and keep costs low for consumers. Specifically, we ask that the AESO: 1. Provide more detail on how behind-the-fence cogeneration load is modeled once cogenerators have declared their preference for net-to-grid or gross-to-grid treatment to ensure that there is no free-ridership from behind-the-fence load; 2. Explain how the use of 3 or 5 economic forecast scenarios would impact the load forecast and whether the forecast is sufficiently robust to ensure reliability.

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6. CONE: Can you support the intended Gross CONE estimation approach?	***Generally, yes – but the AESO must take additional steps to ensure that Gross CONE is calculated properly to send the right price signal in the capacity market for new investment when needed to ensure reliability.*** It is imperative that Gross CONE reflect the unique development and financing environment for merchant generators in the Alberta market. To reflect the uniqueness of Alberta and help ensure a reliable system, we recommend the following areas for continued focus: • We support the simple-cycle gas turbine as the reference technology as peakers are used as the reference technology in most other capacity markets, and a small turbine is appropriate for a market of Alberta's size. • The construction costs in the Gross CONE estimation must be Alberta-specific, reflecting a view of labour and construction costs from construction companies' active in Alberta and the costs of new transmission and gas pipeline infrastructure. • The financing costs in the Gross CONE estimation must also be Alberta-specific, reflecting a view from lenders active in Alberta and the lower debt and higher lending rates of Alberta projects. These financing costs must reflect the equivalent risk profile of a merchant generator with a one-year contract. **<u>Detailed Response:</u>** Gross CONE estimates are a crucial component of estimating Net CONE that ultimately shapes the demand curve in the capacity market. Therefore, appropriate Gross CONE calculation is critical for sending the appropriate capacity price signal to encourage needed investment to ensure system reliability. It is of utmost importance that the Gross CONE calculation in Alberta accurately reflect the cost of development and construction in Alberta as well as Alberta-specific financing assumptions. TransAlta supports the investigation of simple-cycle gas turbines as the reference technology. We support the use of LM6000, LMS100 and EA frames. We disagree with considering internal combustion engines such as Wartsila's as a reference technology as these types of units are generally only used for on-site load requirement applications rather than for grid power applications. We also have concerns that there are fewer examples of these applications in practice, which presents issues in terms of creating a representative sample of projects from which to estimate Gross CONE. TransAlta emphasizes the importance of undertaking a capital cost study that reflects Alberta-specific development and construction costs. While we can support the bottom-up cost estimation approach proposed by Sergeant & Lundy, we do have concerns that surveys of vendors throughout North America may not be truly reflective of actual costs in Alberta. We note that project costs outside of Alberta can often be lower than in Alberta due to differences in costs for equipment built to Alberta-specific regulatory standards as well as unique labour and construction costs. We strongly encourage that the process for developing Gross CONE

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	includes reviews of actual projects in Alberta as well as consultations with developers and generation project owners to ensure that those costs are appropriate for Alberta. TransAlta also believes that transmission and gas fuel supply costs are material and need to be properly considered. Transmission interconnection costs in Alberta differ based on location and need to be properly captured in Gross CONE. Gas fuel supply costs will also be significant and should also capture the costs for firm gas supply. Finally, TransAlta believes that it is critically important to use of Alberta-specific financing assumptions to calculate Gross CONE. Getting these financing assumptions right is crucial for the proper function of the capacity market, which is to help investors manage risk and encourage market-based private investment in capacity resources needed to maintain reliability via annual capacity supply obligations without needing to resort to long-term contracts for capacity that would unfairly shift investment risk onto consumers. We appreciate that there are difficulties in determining financing assumptions in Alberta due to the historic absence of project financing in Alberta. However, this underscores the importance of not relying on financing assumptions from other jurisdictions where project financing is common. Alberta's uniquely small market size is a key reason why the options to hedge financing risk are limited and market liquidity is low. While lenders will in time become comfortable with the capacity market, the sheer limitation in market size will be a persistent issue in Alberta that will contribute to a consistently conservative financing environment, as will the reality that investment risk will reflect that of a merchant generator with a one-year supply contract. For this reason, we believe that there is a practical cap to leverage for all projects, and we expect that this cap will limit debt to equity ratios to 20/80. We also believe that debt costs will reflect a higher spread for the merchant risk related to the Alberta market. In order to develop the right, Alberta-specific financing assumptions, TransAlta strongly encourages Brattle to survey active lenders in the Alberta market. While we understand that this is an approach that Brattle has not taken in the past, we believe that it is a valuable and necessary process for the development of a truly accurate Gross CONE estimate for the Alberta market. We also believe that Brattle's discussions with generation owners will provide insights into how projects are financed and key assumptions that should be adopted for use in Alberta.
7. CONE: What are the important considerations AESO needs to take into account when selecting the Energy and Ancillary Service offset estimation methodology?	***We are concerned that the AESO is not reflecting appropriate energy market bidding behavior in its Energy and Ancillary Service offset estimation methodology.*** Accurately estimating the Energy and Ancillary Service offset methodology is imperative to properly estimating Net CONE and setting the demand curve such that new and existing generators receive a sufficient price signal to be on the system when needed for reliability. Overestimating the offset threatens the reliability of the system by failing to incentivize new generation entry through Net CONE. We recommend the following changes to improve the offset calculation methodology:

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	• Energy market bidding for thermal resources must be limited to SRMC, both to reduce price volatility in the energy market and keep costs low for consumers and to avoid the forecasting error inherent in modeling behavior of economic withholding. • Forecasted energy and ancillary service revenues must reflect *expected* future bidding behavior under an appropriate energy market mitigation framework where thermal resources are limited to SRMC bidding, not bidding behaviour from the historical energy-only market where economic withholding and shadow bidding were permitting. Using historical bidding behavior will artificially inflate energy revenues, which will decrease Net CONE and threaten capacity price fidelity. **Detailed Response** The capacity market is not guided by historical energy-only offer behavior, which allowed for economic withholding that was supported by the Market Surveillance Administrator's Offer Behaviour Enforcement Guideline. In fact, economic withholding is strictly prohibited in North American and European capacity markets, and we strongly recommend that the AESO firmly limit thermal generators to SRMC bidding. As such, it makes no sense for the AESO to model energy prices based on historical offer behaviour adjusted for energy offer market mitigation to 3x SRMC. Therefore, we first request that the AESO be clearly establish an energy market mitigation framework that limits thermal generators to SRMC bidding. We also request that the AESO and the MSA be fully transparent about their views about future offer behavior. Specifically, we request that the MSA's comments be made public so that their views on market monitoring and enforcement can be accurately reflected in the energy and ancillary service methodology. At a minimum, we would expect that this modeling be based not on historical energy-only offer behavior but on behavior that reflects the existence of a capacity market and rules-based limits on above-SRMC bidding.
8. CONE: Are there any issues or gaps in our considerations or plan in Net CONE estimation?	***Yes - Net CONE estimation must account for greenhouse gas (carbon) costs.*** The greenhouse gas framework and price level of carbon costs are significantly different between Alberta and other capacity markets, and any future changes to the carbon tax level can dramatically impact estimated energy and ancillary service revenues, which can in turn impact the effectiveness of the capacity price signal for investment needed for reliability. We suggest a flatter (or less steep) demand curve can help address this risk, thereby supporting the AESO and government's desire for lower and less volatile prices for consumers.

General Comments: Any comments on relevant scope areas of the CMD that are not addressed above

TransAlta sincerely appreciates the AESO's efforts to date related to integrated capacity and energy modeling as well as resource adequacy modeling, both of which are needed by industry participants in order to have confidence in the market design. We firmly believe that transparency in the resource adequacy modeling process is critical to ensuring accurate outcomes that support a reliable system, and that the collective expertise of market participants can be leveraged by the AESO to refine and improve the modeling process.

In light of this drive for continued improvement, we would like to flag some issues that we have identified related to integrated capacity and energy modeling that was performed for CMD1. In particular, we are concerned that the modeling has not yet shown that the market design will be effective in retaining sufficient generation over time to yield stable prices and reliable service for consumers.

1. ***Too much is assumed:*** The AESO states that the markets will be so "integrated" as to ensure that insufficient energy market profits will be recouped from the capacity market through self-correction. This statement suggests that the AESO has perhaps has not captured the reality that energy and capacity markets are integrated only through expectations of what will happen in the energy market. In reality, there is limited opportunity for self-correction given that capacity auctions occur approximately three years before energy market deliveries begin for an obligation period. Additionally, there is no guarantee that any shortfalls in revenues from the energy market in one period would be recouped in future (and unrelated) capacity market periods, as economic losses from prior years are not recognized as part of net go forward fixed costs that existing generators are allowed to bid into the capacity market.

For example, if a generator loses money in 2025 based on the combination of a low capacity price that was set in a 2022 auction combined with unexpectedly low energy prices in 2025, that generator is not permitted to recover a true-up outside of the market. Nor can it roll forward losses and expect to recoup them in the next capacity auction. If the generator did try to include past losses as part of its bid in the next capacity auction its bid was not mitigated, its bid price would have to rise, which would increase the risk that the generator would not clear the auction due to competition from other resources. The AESO has overlooked this risk in its modeling.

2. ***The models are not dynamic:*** The AESO's approach is not endogenously determining expected new entry and investment decisions. Rather, the AESO administratively imposes a specific amount and type of new entry and then models market outcomes assuming that the entry would occur as specified. Based on this setup, the AESO cannot conclude whether the entry is in fact going to (or is even likely to) happen. The modeling also does not appear to consider economic retirements. For these reasons, we would describe the modeling as "static", and it is not possible to determine the likelihood that the market design will deliver the investment needed to provide reliable service to consumers. Given the overarching objective to design and operate a market that delivers reliable service, we believe AESO's modeling approach is incomplete. Therefore, the AESO should consider refining the modeling tools so that they can project when and how much investment would be triggered and whether there would be any economic retirements in order to determine the expected effectiveness of the market design in meeting reliability targets

3. ***There are too many unnecessary layers:*** The AESO appears to have implemented two layers of energy market modeling. The first layer consists of Aurora-based simulations, while the second layer is an Excel-based dispatch tool to assess the profitability of new entrants. We do not understand why the profitability of the new entrants cannot be calculated directly from the Aurora runs, and we are concerned that the Excel-based analysis layer introduces unnecessary averaging (at best) or errors in estimating the running regime and profits of generators.

4. ***Missing analysis of key market elements and CMD components:*** Several of the key elements of the CMD are not being modeled in the capacity market. The AESO has stated that it has not considered the implications of its proposed capacity performance framework. Moreover, the AESO has not properly modeled UCAP in the capacity market - it assumed that thermal assets' UCAP was equal to 100% of the installed capacity, but the CMD dictates that UCAP would be derated for availability of such resources in the top 100 tightest hours. Furthermore, the AESO has not tested net-to-grid treatment, although the CMD opens net-to-grid treatment as an option for cogeneration. Finally, ancillary services revenues were not considered despite the fact that such revenues are crucial for signaling and remunerating desired flexibility and are an important source of revenues for certain existing assets.

5. ***Possible future market conditions and other CMD options not tested:*** The AESO claims that the results of this modeling supports the conclusion that the proposed market design will yield stable prices, but results from three scenarios are not sufficient to make this conclusion. For example, the AESO has not tested what could happen with lower gas prices or lower demand. In addition, in order to be able to truly say that the CMD supports stable prices, the AESO should have tested alternative CMD design elements. For example, considering varying market power mitigation schemes, UCAP approaches, or capacity performance schemes would help identify the market design package that indeed delivers the most stable prices.

The benefits of an integrated modeling approach are unquestionable, but before conclusions can be drawn, the modeling must be improved. If we have misinterpreted the integrated modeling, we request that the AESO respond with more detailed documentation and explanation. Many stakeholders (including TransAlta) would appreciate seeing the additional details around the AESO's inputs and outputs. We also urge the AESO to consider working with industry through the Technical Working group to refine the integrated modeling analysis. A more collaborative process will also help educate various stakeholders on the details on the market design that we all working together to implement.

We also request that the following information be provided with respect to resource adequacy modeling:

1. Annual AIL and AIES energy load and peak demand forecasts used and source documents.
2. 8760 hours per year hourly load profiles used indicating if this is AIL load, AIES load or some other quantity and source documents for forecast.
3. Assumptions around price responsiveness of load if any
4. The assumed Maximum Continuous Ratings (MCR) of all generators shown on an hourly basis if these change.
5. The assumptions on hourly available transmission capability and import capability on all tielines
6. The assumptions on hourly wind generation profiles for all wind generators
7. The assumptions on annual wind generation capacity factors
8. The assumptions on hourly solar generation profiles for all solar installations
9. The assumptions on annual solar generation capacity factors
10. The assumed availability of all generators broken down to show unavailability due to planned maintenance and unavailability due to forced and unplanned maintenance outages.
11. Assumptions on any derates to all generators including seasonal derates.
12. Assumed Forced and unplanned Maintenance Outage Rates (F+MOR)
13. Assumptions on Mean Time To Repair (MTTR) for all generators following a forced or unplanned maintenance outage.
14. Assumptions on hourly hydro capability to provide energy and regulating, spinning, and supplemental reserves broken down by river system for Bow, Bighorn, and Brazeau river systems.
15. Assumptions on annual hydro energy production at the Bow, Bighorn, and Brazeau river systems
16. Assumptions on hourly hydro energy production from run of river and irrigation hydro systems
17. Assumptions on capability to provide regulating reserves, spinning reserves and supplemental reserves over each of the tielines
18. Assumptions on capability to provide regulating reserves, spinning reserves and supplemental reserves for each generator on the system.
19. Assumptions if any transmission congestion is anticipated.
20. Assumptions on the hourly modelling of cogeneration by facility – such as are the co-generator and the onsite load both modelled or is the co-generation modelled as net to grid
21. Assumptions on minimum stable loading for all generators and start times for all generators
22. Assumptions on ramp rates for all generators.
23. Assumed planned maintenance schedules for all generators
24. Assumed generator additions and retirements and timing specifying type of generator MCR, F+MOR, derates, start times, minimum stable operating levels, ramp rates.
25. Assumed planned maintenance schedules for all tielines
26. Any assumptions around increased tieline capability.
27. Assumptions for modelling any storage facilities that are included.